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Power Plant Investment and
Regional Electricity Markets

Sithe New England

May 2001

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Overview

- What it costs to build a new power plant
- What it costs annually to build & operate a plant
- How the regional wholesale markets work
- How the owner of a new power plant makes money
- Relationships between capacity markets & reliability
- Why ICAP (or something like it) is needed

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What it costs to build a new power plant

- Example: new baseload plant in New England
  - 500 MW, high efficiency, gas-fired combined cycle plant
  - enough power to provide electricity to about 200,000 homes
  - 3 - 5 years lead time (development, permitting, construction)
  - $200 - $400 million total capital cost
- Example: new peaking plant in New England
  - 125 MW, moderate efficiency, gas-fired combustion turbine plant
  - enough power to provide electricity to about 50,000 homes
  - 2 - 4 years lead time (development, permitting, construction)
  - $40 - $80 million total capital cost

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The level of new power plant investment

- New power plant capacity additions in NE
  - 2,700 MW - recently entered service 1999-to present
  - 7,600 MW - under construction, to enter service 2001-2004
  - total = 10,300 MW
- Total investment in new power plant capacity in NE
  - Approximately \$6 - \$8 Billion
  - Does not include investment to purchase existing units

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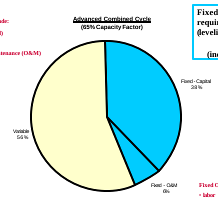
What it costs to build & operate a plant annually

Variable costs include:
- •fuel (natural gas, oil)
- •NOx allowances
- •operations & maintenance (O&M) (e.g., lubricants)
- •etc.



Fixed revenue requirement (levelized) = \$95 - 140 / kw-yr

(includes fixed capital & fixed o&m)

Fixed capital costs include:
- •constructioncosts(labor, equipment)
- •financingcosts(debt)
- •profit (return of and on equity)
- •other (development, permitting, land, etc.)
- •transmission interconnection
- •etc.

Fixed O&M includes:
- labor
- fuel storage
- insurance
- taxes
- etc.

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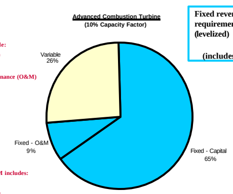
What it costs to build & operate a plant annually



Fixed revenue requirement (levelized) = \$60 - 90 / k w-yr

(includes fixed capital & fixed o&m)

Variablecostsinclude:
- •fuel (natural gas, oil)
- •NOx allowances
- •operations & maintenance (O&M) (e.g.,lubricants)
- •etc.

Fixed O&M includes:
- •labor
- •fuelstorage
- •insurance
- •taxes
- •etc.

Fixed capital costs include:
- •constructioncosts(labor, equipment)
- •financingcosts(debt)
- •profit (return of and on equity)
- •other (development, permitting, land, etc.)
- •transmission interconnection
- •etc.

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How the regional wholesale power markets work

- Multiple markets administered by ISO-NE:
  - energy - hourly spot market
    - generators bid price ($/MWH) to provide supply in a particular hour
    - hourly price equals bid of the marginal generator needed to meet load
    - generators paid when dispatched, no payment when not
    - all resources paid market clearing price
    - uplift paid to dispatched resources with bid greater than market clearing price (bid of resources receiving uplift evaluated as $0/MW, lowering market price)
  - ancillary services - hourly spot markets
    - payments for reserve and balancing services
  - ICAP - monthly market for installed capacity
    - pricing based on offered/accepted prices ($/kW-month) to provide capacity
    - capacity deficiency charge sets maximum price paid by load. Load typically pays significantly less than this charge in bilateral contracts.
- Note: also bilateral contracts for energy and ancillary services

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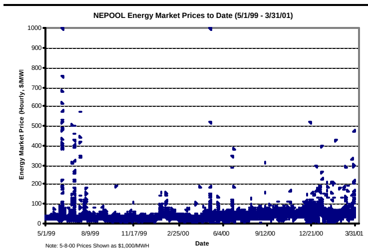
Prices in New England’s regional energy market



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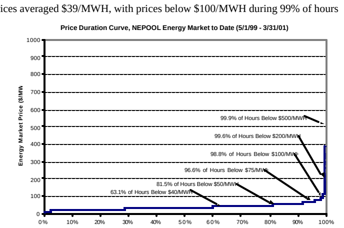
Prices in New England’s energy spot market

Prices averaged $39/MWH, with prices below $100/MWH during 99% of hours



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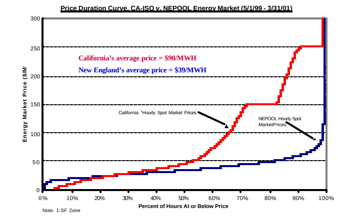
Prices in energy spot markets: New England & California

New England's spot energy prices are lower and less volatile than California's



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How the owner of a new power plant makes money

- Generator paid energy clearing price when it runs
  - no payment in energy market when it doesn't run
  - uplift payment in instances when dispatched but when the energy clearing price is insufficient to cover the generator's bid
  - payment subject to market monitoring and mitigation
- Energy market revenues above variable costs ("net revenues") available to cover fixed cost
- Relatively small amounts of additional revenue paid when generator provides ancillary services
- Generating unit profitability measured by comparing net energy and ancillary service revenues, to revenues required to cover fixed costs over life of unit ("revenue requirement")

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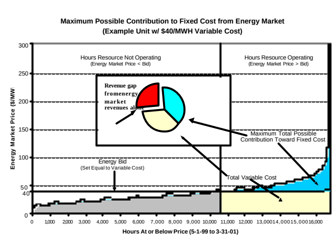
How the owner of a new power plant makes money



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How the owner of a new power plant makes money

Example 1: 500 MW gas-fired combined cycle

- Fixed cost requirement (levelized) $95 - $140 per kw-yr
- Expected net revenues: less
  - energy market $50 - $70 per kw-yr [1]
  - uplift $1 - $1.5 per kw-yr [2]
  - ancillary services $2 - $2.5 per kw-yr [3]
  - total $53 - $74 kw-yr

equals

- **revenue gap** **$21 - $87 kw-yr [4]**

Notes:
1 - The maximum theoretical spot energy contribution to fixed costs (energy revenues less variable cost - i.e., blue area on previous slide) = $79.42 per kw-yr (5/1/99 - 3/31/01). This assumes "perfect" dispatch at full capacity whenever the plant's variable costs are at or below the actual hourly spot price with no outages or other operational constraints. This calculation based on Bostoncitygate daily prices for natural gas, average heat rate of 7,500 BTU/kwh (the efficiency of new combined cycle units on line during the study period), and variable O&M equal to $0.51MWH .
2 - The average uplift payment for all capacity for period 5/1/99 to 3/31/01 was $2.85/kw*yr, mostly received by older steam units with less flexible operating characteristics. The value used here was adjusted to account for relatively small portion of uplift likely to go to flexible new combined-cycle capacity and for portion of uplift payment covering variablecosts.
3 - The average payment for ancillary services for period 5/1/99 to 3/31/01 was $2.98k w*yr. The value used here was adjusted to account for capabilities of unit and portion of revenues representing lost opportunity costs in energy market (i.e., revenue already counted above).
4 - These "revenue gap" values are not a sufficient basis to calculate appropriate ICAP deficiency charge, since the deficiency charge is intended to set maximum revenue in ICAP market and therefore must be set higher than expected market prices. In addition, the appropriate deficiency charge must be adjusted to account for month-to-month and year-to-year volatility in ICAP prices and may include a penalty factor.

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How the owner of a new power plant makes money

Example 2: 125 MW gas-fired combustion turbine

- Fixed cost requirement (levelized) $60 - $90 per kw-yr
- Expected net revenues: less
  - energy market $25 - $40 per kw-yr [1]
  - uplift $0.5 - $1 per kw-yr [2]
  - ancillary services $2.5 - $3 per kw-yr [3]
  - total $28 - $44 kw-yr

equals

- **revenue gap** **$16 - $62 kw-yr [4]**

Notes:
1 - The maximum theoretical spot energy contribution to fixed costs (energy revenues less variable cost - i.e., blue area on previous slide) = $44.65 per kw-yr (5/1/99 - 3/31/01). This assumes "perfect" dispatch at full capacity whenever the plant's variable costs are at or below the actual hourly spot price with no outages or other operational constraints. This calculation based on Boston citygate daily prices for natural gas, average heat rate of 9,500 BTU/kwh, and variable O&M equal to $0.51/MWH.
2 - The average uplift payment for all capacity for period 5/1/99 to 3/31/01 was $2.85/ k w*yr, mostly received by older steam units with less flexible operating characteristics. The value used here was adjusted to account for relatively small portion of uplift likely to go to flexible new combined-cycle capacity and for portion of uplift payment covering variable costs.
3 - The average payment for ancillary services for period 5/1/99 to 3/31/01 was $2.98/ k w* yr. The value used here was adjusted to account for capabilities of unit and portion of revenues representing lost opportunity costs in energy market (i.e., revenue already counted above).
4 - These "revenue gap" values are not a sufficient basis to calculate appropriate ICAP deficiency charge, since the deficiency charge is intended to set maximum revenue in ICAP market and therefore must be set higher than expected market prices. In addition, the appropriate deficiency charge must be adjusted to account for month-to-month and year-to-year volatility in ICAP prices and may include a penalty factor.

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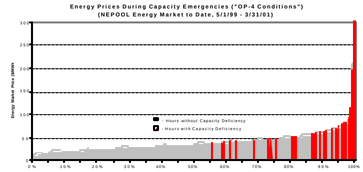
Relationship between capacity markets & reliability

- Reliable energy markets do not appear to provide adequate compensation to support capacity investment. Hours for which prices are high are much more likely to be associated with unreliable operation.
- Example: New England prices



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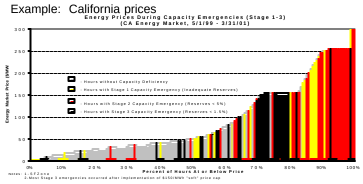
Relationship between capacity markets & reliability

- Energy markets may provide adequate revenues to support investment, but such a market is likely to have extended periods of chronic unreliability.
- Example: California prices



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Why ICAP (or something like it) is needed

- ICAP is needed to assure adequate entry of new generation capacity for reliability purposes
  – Revenues from reliable spot energy and ancillary service markets are not adequate to compensate investors in new generation capacity
  – An additional compensation mechanism is necessary to make up the difference in revenues between:
    - what can be reasonably expected to be produced in energy and ancillary service markets, and
    - what is needed to ensure adequate & sustainable investment returns

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Why ICAP (or something like it) is needed

- The link between reliability and the capacity market:
  – A capacity market is needed to:
    - provide additional compensation needed to provide adequate returns on investment, so as to avoid periods where inadequate capacity exists on the system to provide reliable operation to meet demand
    - help avoid periods of especially high energy prices associated with unreliable levels of scarce supplies*
    - assures that generating capacity is available to serve New England, as opposed to being exported to other regions

* Note that California lacks an ICAP market

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Why ICAP (or something like it) is needed

- Currently expected capacity surpluses over the next few years could change quickly:
  - In the short run, New England appears to have sufficient capacity (both built and under construction)
  - When new capacity comes on line, a significant amount of existing capacity will be at risk economically
  - A portion of existing capacity is likely to *[will]* retire, and the apparent surpluses could change quickly.
- Additional factors that may lead to retirement include:
  - Stricter environmental regulations
  - License expirations
  - Capital costs to repair/overhaul aging equipment

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Why ICAP (or something like it) is needed

- Expected incremental capacity outlook:

– estimated capacity additions	10,300 MW
– estimated load growth ('00-'04)	-1,700 MW
– changes in import/export levels*	-2,600 MW
– net additions of capacity	6,000 MW

- Potential retirements of existing NE capacity:

– 40+ year-old steam cycle plants	2,200 MW
– 30-40 year-old steam plants	3,900 MW
– 30+ year-old direct-fired plants	900 MW
– 25+ year-old nuclear plants	1,900 MW
– wood/other	800 MW
– total	9,700 MW

* Resulting primarily from expiration of the Hydro Quebec firm energy contract, decreased ability to import from New Brunswick due to increased congestion, and expected decreases in imports/increases in exports over New York ties.

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Summary

- Generators are making a large fixed investment in the region
- Fixed cost typically represents roughly half or more of the total costs of producing power
- Revenues from energy and ancillary service markets alone are inadequate to recover of and on capital investments when sufficient capacity exists to ensure system reliability
- Another compensation mechanism (like ICAP) is needed to support a reliable regional electric system
- Apparent short-run adequacy of existing and planned capacity may quickly erode without ICAP market

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ICAP Myth #1

- Myth:
- Prices in New England's spot market are high enough to produce adequate revenues to induce entry into the market
- Reality:
- While prices are somewhat volatile during brief periods when capacity reserves are low, average energy spot market prices in New England have been stable ($39/MWh)

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ICAP Myth #2

- Myth:
- Wholesale energy spot market revenues in New England are high enough to support new entry.
- Reality:
- Energy and ancillary service revenues alone will not support new investment. Market experience to date* shows a gap between new plant revenue requirements and energy and ancillary service revenues:
  - required revenues for new plant **: $95 to $140 / kw-yr
  - expected net energy & ancillary revenues: $53 to $74 / kw-yr
  - revenue gap: $21 to $87 / kw-yr

* 5-1-99 to 3/31/01, a period when the region has generally been reported to be short of installed capacity
** new combined cycle plant

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ICAP Myth #3

- Myth:
- There are so many plants being built that investors must think that prices will support entry without ICAP
- Reality:
- The ICAP market helped spur capacity additions in New England. Capacity now in construction or just entered service was committed to before the recent movement to eliminate (or greatly reduce) the ICAP market.

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ICAP Myth #4

- Myth:
- With so much new capacity being added and no retirements, we'll be awash in surplus capacity, and we don't need further new investment.
- Reality:
- It's too early to tell whether and if so how much existing capacity will retire. A significant amount of existing capacity is at economic risk when the new capacity comes on line. There will be increased financial pressure to retire some existing capacity. When that occurs, the apparent capacity surplus could quickly change to a deficiency.

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ICAP Myth #5

- Myth:
- ICAP isn't really a product, since nothing is produced.
- Reality:
- ICAP represents real financial and performance obligations on the part of generators, who *must* provide capacity to New England when needed. To date, these obligations on generators to provide capacity to New England have not been adequately tied to the compensation mechanisms (e.g., through recallability, etc.).

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ICAP Myth #6

- Myth:
- ICAP isn't needed, because it trades at low prices.
- Reality:
- Capacity prices vary over time, depending upon the supply of capacity relative to load and reserve requirements as well as outstanding commitments of parties. The price of capacity may be near zero at times, approach the cost of constructing a new quick start generating resource at others, or something in between. The *value* of capacity *to consumers* may range anywhere from zero (when it's plentiful) to thousands of dollars per kilowatt when capacity is unavailable and customers experience involuntary power interruptions.

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ICAP Myth #7

- Myth:
- ICAP is a new product set up to provide generators extra payments that were never needed by electric utilities under regulation.
- Reality:
- ICAP was established long before deregulation as a means for ratepayers to compensate utilities for capacity purchased from each other to meet reliability criteria. Most utilities self-supplied the large majority of their capacity for which they were guaranteed fixed cost recovery through rate-of-return regulation. In many cases, utilities continue to collect capacity payments for capacity that they no longer own (and that may even no longer be operating) through "stranded investment" charges that are built into current rates.